CHAPTER 3

LARGE SOURCES - CONTINUOUS PROCESS MONITORING SYSTEM (CPMS)

TABLE OF CONTENTS

CHAPTER 3 - LARGE SOURCES - CONTINUOUS PROCESS MONITORING SYSTEM (CPMS)

This chapter describes the methodologies for measuring and reporting emissions from large sources. For this category, the Facility Permit holder shall use Continuous Emissions Monitoring System (CEMS) or elect to use CPMS to measure NO_X emissions. The focal point shall be the emission factor (during the interim period only, January 1, 1994 to December 31, 1994 for Cycle 1 facilities and July 1, 1994 to July 1, 1995 for Cycle 2 facilities), concentration limit, or equipment-specific emission rate. Mass emissions shall be estimated by using the emission factor (e.g. lb/mm Btu), or concentration limit (e.g. ppmv converted to lb/mm Btu) and a throughput rate (typically fuel consumption adjusted for heating value).

Measurement and reporting requirements apply to variables used to calculate the NO_X emissions. These measured and process variables are found in Table 3-A. The reporting variables are found in Table 3-B.

In accordance with Rule 2012, the Facility Permit will specify either a concentration limit or an emission rate. One or more measured variables necessary to substantiate the equipment-specific emission rate shall be monitored and recorded. These measured variables are listed in Table 3-A. For sources subject to a concentration limit, only fuel usage or throughput is required to be measured by dedicated fuel meters or by any devices approved by the Executive Officer to be equivalent in accuracy, reliability, reproducibility, and timeliness.

Tables 3-C through 3-F list the rule-specific concentration limits, the emission fee billing factors, the unregulated default control efficiencies, and the standard oxygen concentrations.

The criteria for determining large source category is found in Table 1-B.

Starting January 1, 1994 (Cycle 1 facilities) and starting July 1, 1994 (Cycle 2 facilities), large-source NO_X emissions shall be allowed to use an interim reporting procedure to calculate and record on a monthly basis according to the requirements specified in Chapter 3, Subdivision D, Paragraph 1, and Chapter 3, Subdivision G, Paragraph 2 "Large Sources - Continuous Process Monitoring System (CPMS)" . On and after January 1, 1995 (Cycle 1 facilities) and July 1, 1995 (Cycle 2 facilities), the Facility Permit holder of each large source shall report consistent with all other applicable requirements specified in this chapter.

A. GENERAL REQUIREMENTS

1. The Facility Permit holder of a large NO_X source who has elected to use a concentration limit shall comply with any one of the following, in ppmv and over any continuous 60 minutes:

    a. The Facility Permit holder shall be allowed to use the emission factors and/or control efficiencies listed in Tables 3-D, and 3-E or Table 1 of Rule 2002 and apply methodology presented in Subdivision 3, Paragraph C to derive a corresponding concentration limit; or

    b. If there is no applicable concentration limit and/or control efficiency, then the Facility Permit holder shall be allowed to request a manufacturer's guaranteed emission factors and/or control efficiency or a manufacturer's guaranteed concentration limit as part of the Facility Permit application; or

c. The Facility Permit holder shall be allowed to use applicable rule-specific concentration limit found in Table 3-C; or

d. The Facility Permit holder shall be allowed to use any other concentration limit as approved by the Executive Officer according to guidelines set forth in this chapter.

2. The Facility Permit holder of a large NO_X source who has elected to use a concentration limit shall calculate the mass emissions according to the methodology specified in Chapter 3, Subdivision D, Paragraph 2, Subparagraph a.

3. The Facility Permit holder of a large NO_X source who has elected to use an emission rate shall apply the methodology specified in Chapter 5 to derive an acceptable emission rate.

4. The Facility Permit holder of a large NO_X source who has elected to use an emission rate shall calculate the emissions according to the methodology specified in Chapter 3, Subdivision D, Paragraph 2, Subparagraph b.

5. The Facility Permit holder of each equipment shall measure and record fuel usage and one or more parametric variables in Table 3-A in order to substantiate the equipment-specific emission rate. As part of the Facility Permit application review, the Executive Officer shall modify the list of Facility Permit holder-selected variables.

6. Fuel flow measuring devices used for obtaining stack flow in conjunction with F-factors and stack flow monitors shall be tested as installed for relative accuracy using the following methods:

a. If the facility uses a fuel flow meter in conjunction with F-factors to determine stack gas volumetric flow rate, the relative accuracy of the fuel flow meter must be determined using District reference Methods 1-4 and a three-run relative accuracy audit (RAA) at normal operating load. The accuracy of the fuel flow measuring system must be determined using the following equation:

$$A = \frac{(C_m - C_a)}{C_a} \times 100 \qquad \text{(Eq. 15a)}$$

where:

A = accuracy of the fuel flow meter (%)

C_m = average flow rate response (scfh)

C_a = average reference method flow rate (scfh)

The value of fuel flow meter accuracy, as defined in Eq. 15a, shall be less than or equal to 15%.

b. If the facility uses a stack flow meter to determine stack gas volumetric flow rate, the relative accuracy of the stack flow meter must be determined using District reference Methods 1-4 and a three-run relative accuracy audit (RAA). The accuracy of the fuel flow measuring system must be determined using the procedure outlined in Chapter 3, (A)(6)(a) above. The accuracy of the stack flow meter shall be less than or equal to 15%.

c. Other acceptable alternatives to the above procedures used to determine the relative accuracy of the facility fuel flow meter or stack flow meter are listed under Chapter 3, Subdivision H.

7. Fuel meters or any devices approved by the Executive Officer to be equivalent in accuracy, reliability, reproducibility, and timeliness, shall be non-resettable and tamper proof. The seals installed by the manufacturer shall be intact to prove the integrity of the measuring device.

Meters which are unsealed for maintenance or repairs shall be resealed by an authorized manufacturers representative.

8. The Facility Permit holder of each large NO_X source shall monitor, report, and maintain the records on a monthly basis the type and quantity of fuel burned, in units of millions of standard cubic feet per month (mmscf per month) for gaseous fuels or thousand gallons per month (mgal per month) for liquid fuels, expressed to at least three significant figures.

9. Monthly NO_X mass emissions shall be reported to the District's NO_X Central Station Computer according to the requirements specified in Chapter 3, Subdivision G.

B. MONITORING SYSTEMS

1. Operational Requirements

The CPMS shall be operated and data recorded during all periods of operation of the equipment including periods of start-up, shutdown, malfunction or emergency conditions, except for CPMS breakdowns and repairs.

2. Performance Standard

All CPMS at each equipment shall, at a minimum, be able to measure the fuel usage once every fifteen minutes. Such measured data shall be accumulated and recorded to represent the monthly fuel usage as specified in Paragraphs B.3.

3. Information Required for Each Monthly Interval

All CPMS at each equipment shall, at a minimum, measure and totalize the following data points for each successive monthly period, expressed to at least three significant figures, and at equally spaced intervals thereafter, except where noted:

a. Fuel usage in units of million standard cubic feet per month (mmscf/mo) for gaseous fuels, or thousand gallons per month (mgal/mo) for liquid fuels. Alternatively, the fuel usage may be calculated from stack gas volumetric flow rates totalized over a month and oxygen concentration, in which case the Facility Permit holder shall measure:

i. Oxygen concentration in the stack in units of percent if required for calculation of the stack gas flow rate.

ii. Volumetric flow rate of stack gases in units of dry standard cubic feet per month. Standard gas conditions are defined as a temperature at 68°F and one atmosphere of pressure.

b. One or more process variables specified in Table 3-A, if the Facility Permit holder elects for an equipment-specific emission rate.

C. CONCENTRATION LIMIT CALCULATION

Pursuant to the election condition requirements in Rule 2012 (f), the Facility Permit holder shall use the equation provided in this section to calculate the concentration limit. Equation 15 applies to the Facility Permit holder requesting that the Emission Fee Billing factor in Table 3-D, the emission factor specified in Table 1, Rule 2002 - Baselines and Rates of Reduction for NO_x/SO_x and/or the control efficiency in Table 3-E be converted into a concentration limit.

$$PPMV_c = 0.8368\text{x}10^7 \text{ x } (20.9\text{-b}/20.9) \text{ x } \sum_{j=1}^{r} EF_j \ (1\text{-}EFF_j)/(F_{dj} \text{ x } V_j) \quad \text{(Eq.15)}$$

where:

$PPMV_c$	=	The equipment-specific concentration limit corrected at applicable standard oxygen concentration found in Table 3-F or rule-specific concentration limit found in Table 3-C.
EF_j	=	The equipment-specific EFB emission factor (lb/mmscf or lb/mgal) found in Table 3-D or emission factor found in Table 1 of Rule 2002 or reported value of emission factor. The emission factor found in Table 1 of Rule 2002 may or may not include the appropriate control efficiency.
EFF_j	=	The equipment-specific control efficiency (%), found in Table 3-E or proposed by the Facility Permit holder.
b	=	The standard oxygen concentration (%) found in Table 3-F.
F_{dj}	=	The fuel-specific dry F factor, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel(dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.
V	=	The higher heating value for each type of fuel (mmBtu/mmscf or mmBtu/mgal) found in Table 3-D.

j	=	Each type of equipment in a large NO_x source sharing a fuel meter and identical concentration limit at standard oxygen concentration.
r	=	The total number of equipment in a large NO_x source sharing a fuel meter and identical concentration limit at standard oxygen concentration.

Example Calculation: Natural-Gas Fired Boiler with Lo-No_x Burner

EF	=	130 lb/mmsf
V	=	1,050 mmBtu/mmscf
EFF	=	35%
b	=	3%
F_d	=	8,710 dscf/mmBtu
$PPMV_c$	=	130 (1 - 35/100) x [(20.9 - 3)/20.9] x 0.8368 x 10^7/(8,710 x 1,050) =70 ppmv

D. EMISSION CALCULATION FOR REPORTED DATA

1. Monthly Mass Emissions for Interim Periods

Pursuant to Rule 2012 (f) (1), between January 1, 1994 and December 31, 1994 for Cycle 1 facilities, and between July 1, 1994 and June 30, 1995 for Cycle 2 facilities, the monthly emission of each large source shall be calculated and recorded according to:

$$E_{ip} = \sum_{j=1}^{r} EF_{sj} \times d_j \qquad \text{(Eq.16)}$$

where:

E_{ip}	=	The monthly mass emission of nitrogen oxides for interim period (lb/month).
EF_{sj}	=	The starting emission factor used to calculate source emissions in the initial allocation, as specified in Table 1 of Rule 2002 - Allocations for NO_x/SO_x (lb/mmscf, lb/mgal).
d_j	=	The monthly metered fuel usage for each type of fuel recorded as mmscf/ month or mgal/month.
j	=	Each type of fuel used, or material processed or produced by a large NOx source
r	=	The total number of fuel types used, or materials processed or produced by a large NOx source

Example calculation:	Boiler burning natural gas, rated 40 mmBtu/hr, in compliance with Rule 1146.		
	Applicable starting year emission factor	=	49.18 lb/mmscf
	Monthly fuel usage	=	20 mmscf per month
	E_{ip}	=	(49.18) x (20) = 983.6 lb/month

2. Monthly Mass Emissions for Normal Operating Hours

a. When the Facility Permit holder elects to use the concentration limit, the monthly mass emission shall be calculated and recorded according to one of the following equations:

i Use the F-factor approach for oxygen, except in cases where enriched oxygen is used, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), or the oxygen content of the stack gas is 19 percent or greater. The following equation shall be used to calculate and record nitrogen oxides mass emission rate:

$$E_k = PPMV_{O2} \quad [20.9/(20.9 - b)] \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dj} \times d_j \times V_j) \qquad \text{(Eq.17)}$$

where:

E_k	=	The monthly mass emission of nitrogen oxides (lb/month).
$PPMV_{O2}$	=	The RECLAIM concentration limit as listed in the Facility Permit. (ppmv) and based on standardized oxygen concentration in the exhaust stream..
b	=	The standard concentrations of oxygen as listed in the Facility Permit or as found in Table 3-F. (%).
r	=	The number of different types of fuel.
j	=	Each type of fuel.
$F_{d\,j}$	=	The dry F factor for oxygen for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.
d_j	=	The monthly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf per month or mgal per month).
V_j	=	The higher heating value of the fuel for each type of fuel found in Table 3-D (mmBtu/mmscf or mmBtu/mgal) or determined by a continuous analyzer.

The product (d_j x V_j) shall have units of mmBtu per month (mmBtu/month).

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19, a constant F-factor and heating value may be used if the Facility Permit holder demonstrates to the Executive Officer that the natural gas, fuel oil, or other fuels have stable F-factors and gross heating values. A stable F-factor or gross heating value is defined as not varying by more than + or - 2.5% from the proposed constant value. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-factors are assumed to be stable at the value cited in Table 19-1. Any F-factor cited in Regulation XX shall supersede the F-factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder demonstrates that the source-specific F-factor meets the same stability criteria, periodic reporting of F-factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the Facility Permit operator such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) or less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19 and do not satisfy the criteria for constant F-factor and heating value, the fuels must be analyzed on a continuous basis using gas chromatographs or other continuous technique that is approved by the Executive Officer. The continuous technique employed shall be capable of providing at a minimum a reading every fifteen-minute period.

ii. If the F-factor approach for oxygen can not be used, use the F-factor approach for carbon dioxide as specified in 40 CFR Part 60, Appendix A, Method 19, except in cases where the carbon dioxide concentration is less than one volume percent dry, non-fuel sources of carbon dioxide are present (e.g., lime kilns and calciners), or non-metered sources of fuel are present (e.g., afterburners). The following equation shall be used to calculate and record nitrogen oxides mass emission rate:

$$E_k = PPMV_{CO2} \times (100/\%CO_2) \times 1.195 \times 10^{-7} \times \sum_{j=1}^{r} (F_{dj} \times d_j \times V_j) \quad \text{(Eq.17a)}$$

Where:

E_k = The monthly mass emission of nitrogen oxides (lb/month).

$PPMV_{CO2}$ = The RECLAIM concentration limit as listed in the Facility Permit (ppmv) and based on standardized carbon dioxide concentration in the exhaust stream.

$\%CO_2$	=	The standard concentrations of stack gas carbon dioxide as listed in the Facility Permit.
r	=	The number of different types of fuel.
j	=	Each type of fuel.
$F_{d\,j}$	=	The dry F factor for carbon dioxide for each type of fuel, the ratio of the dry gas volume of the products of combustion to the heat content of the fuel (dscf/mmBtu) specified in 40 CFR Part 60, Appendix A, Method 19.
d_j	=	The monthly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf per month or mgal per month).
V_j	=	The higher heating value of the fuel for each type of fuel found in Table 3-D (mmBtu/mmscf or mmBtu/mgal)) or determined by a continuous analyzer.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19, a constant F-factor and heating value may be used if the Facility Permit holder demonstrates to the Executive Officer that the natural gas, fuel oil, or other fuels have stable F-factors and gross heating values. A stable F-factor or gross heating value is defined as not varying by more than + or - 2.5% from the proposed constant value. For the fuels listed in 40 CFR 60, Appendix A, Method 19, Table 19-1, the F-factors are assumed to be stable at the value cited in Table 19-1. Any F-factor cited in Regulation XX shall supersede the F-factor in Table 19-1. For fuels not listed in the citations above, but which the Facility Permit holder demonstrates that the source-specific F-factor meets the same stability criteria, periodic reporting of F-factor may be accepted and the adequacy of the frequency of analyses shall be demonstrated by the Facility Permit operator such that the probability that any given analysis will differ from the previous analysis by more than 5% (relative to the previous analysis) or less than 5%. Analysis records shall be maintained, including all charts and laboratory notes.

For non-standard fuels that are not listed in 40 CFR Part 60, Appendix A, Method 19 and do not satisfy the criteria for constant F-factor and heating value, the fuels must be analyzed on a continuous basis using gas chromatographs or other continuous technique that is approved by the Executive Officer. The continuous technique employed shall be capable of providing at a minimum a reading every fifteen-minute period.

iii. If the F-factor approach for carbon dioxide can not be used, the nitrogen oxides mass emission rate shall be determined based on actual monthly stack flow rate from a continuous stack flow monitor and concentration limit at stack conditions as listed in the Facility Permit. The mass emission rate shall be determined by the following equation:

$$E_k = PPMV_{ST} \times 1.195 \times 10^{-7} \times \sum_{j=1}^{N} F_j \qquad \text{Eq. 17b}$$

where:

E_k = The monthly mass emission of nitrogen oxides (lb/month).

$PPMV_{ST}$ = The concentration limit at stack condition as listed in the Facility Permit (ppmv).

F = Total monthly stack flow rate (scf/month).

N = Number of exhaust stacks.

b. When the Facility Permit holder elects to use the emission rate, the monthly emission shall be calculated and recorded according to:

$$E_k = \sum_{j=1}^{r} d_j \times V_j \times ER_j \qquad \text{(Eq.18)}$$

where:

E_k = The monthly mass emission of nitrogen oxides (lb/month).

d_j = The monthly fuel usage for each type of fuel recorded by the fuel totalizer (mmscf/month or mgal/month) or the monthly amount of materials produced or processed, depending to the units of the equipment specific emission rate.

ER_j = The equipment-specific emission rate proposed by the Facility Permit holder and determined according to Chapter 5, Subdivision E (lb/mmBtu).

V_j = The higher heating value of each type of fuel (mmBtu/mmscf or mmBtu/mgal). This equals 1 if ERj is not dependent on fuel combustion.

Example Calculation:

y	=	Each type of fuel.
r	=	The number of type of fuel consumed per month
Boiler		
ER_c	=	200 lb/mmscf requested for uncontrolled, natural gas fired boiler
d	=	1 mmscf per month
E_k	=	ER_c x d = 200 x 1
E_k	=	200 lb/month
ICE		
ER_c	=	500 lb/1000 gal requested for uncontrolled, natural gas fired ICE
d	=	600 gal/month
E_k	=	ER_c x d
	=	500 lb/1000 x 600 gal/month
	=	300 lb/month
Total E_k	=	200 + 300 lb/month
	=	500 lb/month

3. Monthly Mass Emissions during Startup or Shutdown Periods

The Facility Permit holder of a large source with startup or shutdown periods at least 6 hours in duration shall apply the following methodology to determine the emissions during startup and shutdown periods:

a. During equipment startup or shutdown the Facility Permit holder shall apply the EFB emission factor specified in Table 3-D; or

b. If the emission factors in Table 3-D do not reflect the emission factors during startup and shutdown periods, the Facility Permit holder shall propose emission factors for the approval of the Executive Officer and shall submit source test data to substantiate the proposed emission factors. The monthly emissions during startup and shutdown periods shall be calculated and reported according to:

$$E_{st} = \sum_{j=1}^{r} D_{stj} \times EF_{stj} \qquad \text{(Eq.19)}$$

$$E_{sh} = \sum_{j=1}^{r} D_{sh} \times EF_{sh} \qquad \text{(Eq.20)}$$

where:

E_{st} = The monthly mass emission of nitrogen oxides during startup period (lb/month).

Dstj = The monthly fuel usage for each type of fuel during startup period (mmscf/month or mgal/month), or the amount of materials produced or processed per month depending on the units or proposed emission factors or emission rates..

EFstj = The EFB or Facility Permit holder-specified emission factor or emission rate during startup period (lb/mmscf or lb/mgal

where:

E_{sh} = The monthly mass emission of nitrogen oxides during shutdown period (lb/month).

Dshj = The monthly fuel usage for each type of fuel during shutdown period (mmscf/month or mgal/month) or the amount of materials produced or processed per month, depending on the units of proposed emission factors or emission rates.

EFshj = The EFB or Facility Permit holder-specified emission factor or emission rate during shutdown period (lb/mmscf or lb/mgal).

j = Each type of fuel or material processed or produced

r = The number of each type of fuel consumed per month or the number of material processed or produced per month.

E. TOTAL MONTHLY MASS EMISSION CALCULATION

The total monthly mass emission shall be calculated and recorded for each equipment according to:

$$E = E_k + E_m + E_{st} + E_{sh} \qquad \text{(Eq. 21)}$$

Where:

E = The monthly mass emission of nitrogen oxides (lb/month).

E_k = The monthly mass emission calculated using measured data during normal operation (lb/month).

E_m = The monthly mass emission calculated using substitute data during normal operation (lb/month).

E_{st} = The monthly mass emission calculated during startup period (lb/month).

E_{sh} = The monthly mass emission calculated during shutdown period (lb/month).

Example Calculation:

E_k	=	130 lb/10^6 scf x 420 scf/hr x 480 hr/mo	=	26.2 lb/month
E_m	=	161 lb/10^6 scf x 300 scf/hr x 3hr/day	=	.1449 lb/month
E_{st}	=	130 lb/10^6 scf x 100 scf/hr x 3hr/day	=	.0390 lb/month
E_{sh}	=	130 lb/10^6 scf x 50 scf/hr x 2 hr/day	=	.0130 lb/month
E	=	$E_k + E_m + E_{st} + E_{sh}$ = 26.2 + .1449 + .0390 +.0130	=	26.4 lb/month

F. FLOW DETERMINATION TEST METHODS

1. District Methods 2.1 and 2.3 shall be used to determine the stack gas volumetric flow rate.

2. For District Method 2.1, District Method 1.1 shall be used to select the sampling site and the number of traverse points.

3. District Method 3.1 shall be used for diluent gas (O_2 or CO_2) concentration and stack gas density determination.

4. District Method 4.1 shall be used for moisture determination of stack gas.

G. REPORTING PROCEDURES

1. The total fuel usage data for all large sources in any facility without a RTU or modem shall be reported in a format approved by the Executive Officer.

2. For each equipment the following information shall be stored on-site in a format approved by the Executive Officer:

   a. Calendar dates covered in the reporting period;

   b. Monthly mass emissions for each equipment ;

   c. Identification of the equipment operating days for which a sufficient number of valid data points has not been taken; reasons for not taking sufficient data; and a description of corrective action taken;

   d. Identification of F_d or Fw factor for each type of fuel used for calculation and the type of fuel burned;

   e. Any changes made in type of fuel used and F_d factor, if applicable.

H. ALTERNATIVE QUALITY ASSURANCE PROCEDURES

1. Emission Stack Flow Rate Determination

In the event that more than one source vents to a common stack, the alternative reference method for determining individual source flow rates shall be EPA Method 19. The orifice plates used in every unit vented to a common stack shall meet the requirements in Chapter 3, Subdivision H, Paragraph 3.

2. Quality Assurance Procedures for Volumetric Flow Measurement System

a. Each volumetric flow measurement system shall be audited at least once each calendar year. Successive audits shall occur no closer than six months or after any modification to the process which would significantly alter the flow.

b. If the volumetric flow measurement system is found to be out of calibration by 15 percent or greater, then recalculation of the flow measurement must be performed from the last audit date to the current audit date.

3. Quality Assurance for Orifice Plate Measurements

Each orifice plate used to measure the fuel gas flow rate shall be removed from the gas supply line for an inspection once every 12 months, if the orifice cannot be checked using Reference Methods or other methods that can show traceability to NIST standards. However, with the prior approval of the Executive Officer, orifice plates may be inspected not less than once every 36 months provided the Facility Permit holder demonstrates to the Executive Officer that orifice plates used for 36 months or longer meet the specifications set forth in this paragraph. This demonstration shall be completed by July 1, 1995 or within one year for facilities that enter RECLAIM on and after July 1, 1994. The following items shall be subject to inspection:

a. Each orifice plate shall be visually inspected for any nicks, dents, corrosion, erosion, or any other signs of damage according to the orifice plate manufacturer's specifications.

b. The diameter of each orifice shall be measured using the method recommended by the orifice plate manufacture.

c. The flatness of the orifice plate shall be checked according to the orifice plate manufacturer's instructions. The departure from flatness of an orifice plate shall not exceed 0.010 inches per inch of dam height (D-d/2) along any diameter. Here D is the inside pipe diameter and d is the orifice diameter at its narrowest constriction.

d. The pressure gauge or other device measuring pressure drop across the orifice shall be calibrated against a manometer, and shall be replaced if it deviates more than ±2 percent across the range.

e. The surface roughness shall be measured using the method recommended by the orifice plate manufacturer. The surface roughness of an orifice plate shall not exceed 50 micro inches.

f. The upstream edge of the measuring orifice shall be square and sharp so that it shall not show a beam of light when checked with an orifice gauge.

g. In centering orifice plates, the orifice shall be concentric with the inside of the meter tube or fitting. The concentricity shall be maintained within 3 percent of the inside diameter of the tube or fitting along all diameters.

h. Any other calibration tests specified by the orifice plate manufacturer shall be conducted at this time. If an orifice fails to meet any of the manufacturer's specifications, it shall be replaced within two weeks.

4. Alternative Relative Accuracy Audit

This section is applicable to facility permit holders who may choose to determine the relative accuracy of the fuel flow meters by a direct comparison to a calibrated fuel flow meter (proving meter) instead of conducting velocity traverse reference method tests. The following general requirements apply to this alternative procedure:

a. The alternative RAA shall be conducted by an independent testing laboratory in accordance with NIST traceable industry standards. A non-independent testing laboratory may be used if the laboratory is regulated by the California Public Utilities Commission.

b. The results shall identify as-found and as-left accuracy of pressure and temperature corrected fuel flow rates. Perform all calculations at consistent temperature and pressure as prescribed by the applicable procedure. All fuel flow rates measured by the fuel flow meters must be converted to standard RECLAIM conditions, which are 68°F and one atmosphere pressure.

c. The value of as-left accuracy, as defined in Eq. 22a, shall be 2.5% or less.

d. The alternative RAA must include at least one run at each of two operating loads. These operating loads must be within 10 percent of the lowest historical operating load and 60 to 100 percent of the maximum operating range of the fuel flow meter. The alternative RAA can include one run at one operating load if the testing laboratory is regulated by the California Public Utilities Commission, and is subject to a more stringent as-left accuracy, as defined in Eq. 22a, than specified in subparagraph (H)(4)(c).

e. If the meter is bypassed during the alternative RAA, missing data procedures shall apply.

The following conditions and procedures apply to specific configurations that may be employed to conduct the above mentioned alternative RAA:

f. Procedure 1: Fuel Flow Meters in Series

Fuel flow meter accuracy may be determined by comparing fuel flow rate from a proving meter (test meter) placed in series with the facility fuel flow meter. The proving meter may be either permanent or removable, however, it must be designed and installed in accordance with recognized industry standards. The proving meter's accuracy must be verified to NIST standards prior to series meter proof. Calibration procedures as prescribed by 40 CFR Part 75, Appendix E and the ones cited below may be used to calibrate such fuel flow meters. The accuracy as determined by the following equation must be less than or equal to 2.5% of the upper range value of the flow meter:

$$A = \left| R \;\; B \right| / URV \times 100 \qquad \text{(Eq. 22a)}$$

where:

A	=	flow meter accuracy
R	=	average of flow measurements of the proving meter at each load
B	=	tested at each load average of flow measurements of the meter being
URV	=	upper range value of fuel flow meter being tested

g. Procedure 2: Meter Swapping

The facility fuel flow meter may be swapped with a factory calibrated meter. The calibration procedures outlined in 40 CFR Part 75, Appendix E and the ones cited below may be used for this purpose. Meter calibrations shall be conducted at the flow rates given in the recognized industry standards. The recognized industry standards for calibration are as follows:

Meter Type	Standard
Diaphragm	ANSI B 109.1 or 109.2 (3rd. edition, 1992)
Rotary	ANSI B109.3 (3rd. edition, 1992)
Turbine	AGA Report No. 7 (2nd. edition, 1996)
Orifice	AGA Report No. 3, Part 1 and 2 (1990, 1991) API 14.3 GPA 8185-90

The minimum installation requirements are as follows:

Meter Type	Standard
Diaphragm	ANSI B 109.1 or 109.2, Part V
Rotary	ANSI B109.3, Part V
Turbine	AGA Report No. 7, Section 3
Orifice	AGA Report No. 3, Part 2, Section 2.6

The above calibration standards apply to both Subparagraph (H)(4)(f) and Subparagraph (H)(4)(g). The above installation requirements apply only to Subparagraph (H)(4)(g).

I. MISSING AND INVALID DATA PROCEDURES

1. For each large source or large sources using a common fuel meter or equivalent monitoring device, the Facility Permit holder shall provide substitute data as described below whenever a valid month of fuel usage data or the amount of production or process feed has not been obtained and recorded. Alternative data is acceptable for substitution if the Facility

Permit holder can demonstrate to the Executive Officer that the alternative system is fully operational during meter down time and within + or- 2% accuracy.

2. Whenever data from the process monitor is not available or not recorded for the affected equipment or when the equipment is not operated within the parameter range specified in the Facility Permit, the Facility Permit holder shall calculate substitute data for each month according to the following procedures.

   a. For a missing data period less than or equal to one month, substitute data shall be calculated using the large source(s) average monthly fuel usage for the previous 12 months.

   b. For a missing data period greater than one month, substitute data shall be calculated using the large source(s) highest monthly fuel usage data for the previous 12 months.

   c. For a missing data period greater than two months, or if the facility has no records, substitute data shall be calculated using 100 percent uptime during the substitution period and the large source(s) maximum rated capacity and uncontrolled emission factor for each month of missing data.

   d. For a process monitor which uses a gas chromatograph or equivalent continuous method to continuously determine the F-factor and higher heating value of the fuel (Rule 2012, Appendix A, Chapter 3, Subdivision D.2.a.i), the Facility Permit holder shall use the stack gas flow rate missing data substitution procedure for major sources (Rule 2011 or 2012, Appendix A, Chapter 2, Subdivision E.2).

J. FUEL METER SHARING

1. A single totalizing fuel meter shall be allowed to measure the cumulative fuel usage for more than one equipment in a large NO_X source provided that each equipment has the same concentration limit, emission rate, or emission factor as specified in the Facility Permit and that any equipment in a large NO_x source does not use the annual heat input in order to be classified from a major source to a large source.

2. One or more pieces of equipment in a large NO_x source shall be allowed to share the fuel totalizing meter provided that each equipment elects for the same concentration limit, emission rate, or emission factor as specified in the Facility Permit.

3. Fuel meter sharing for the interim period shall be allowed for those equipment in a large NO_X source with the same emission factor, emission rate, or concentration limit.

K. PROCEDURES FOR LARGE SOURCES MONITORED BY CEMS

The following requirements are applicable when the Facility Permit holder chooses CEMS as a monitoring alternative for large sources.

1. Calculate monthly mass emissions by summing daily mass emissions which are obtained using procedures set forth in Appendix A, Chapter 2, except that the missing data procedures set forth below shall be used whenever valid data is not obtained:

2. Missing Data Procedures for Large Sources Monitored by CEMS

    a. Percentage of data availability shall be calculated according to procedures set forth in Appendix A, Chapter 2, Subdivision E, subparagraph 1a.

    b. Whenever concentration or flow data from the CEMS have been available and recorded for 95 percent or more of the total operating hours of the affected piece of equipment during the previous 365 days, the Facility Permit holder shall calculate substitute data for each hour, when valid data has not been obtained, according to the following procedures.

        i. For a cumulative missing data period less than or equal to 24 hours in a month, substitute data shall be calculated using the average hourly-recorded CEMS value from the previous month. If no emissions occurred during the previous month, clause (K)(2)(c)(iii) shall apply.

        ii. For a cumulative missing data period greater than 24 hours in a month, substitute data shall be calculated using the maximum hourly-recorded CEMS value from the previous month. If no emissions occurred during the previous month, clause (K)(2)(c)(iii) shall apply.

    c. Whenever concentration or flow data from the CEMS have been available for 90-percent or more but less than 95-percent of the total operating hours of the affected piece of equipment during the previous 365 days, the Facility Permit holder shall calculate substitute data for each hour, when valid data has not been obtained, according to the following procedures.

        i. For a cumulative missing data period less than or equal to 24 hours in a month, substitute data shall be calculated using the average hourly-recorded CEMS value from the previous month. If no emissions occurred during the previous month, clause (K)(2)(c)(iii) shall apply.

        ii. For a cumulative missing data period greater than 24 hours but less than or equal to 168 hours in a month, substitute data shall be calculated using the maximum hourly-recorded CEMS value from the previous month. If no emissions occurred during the previous month, clause (K)(2)(c)(iii) shall apply.

iii. For a cumulative missing data period greater than 168 hours in a month, substitute data shall be calculated using the maximum hourly-recorded CEMS value from the previous 12 months or during the service of the monitoring system, whichever is shorter. If no emissions occurred during the previous 12 months, subparagraph (K)(2)(d) shall apply

d. Whenever concentration or flow data from the CEMS have been available for less than 90% of the total operating hours of the affected piece of equipment during the previous 365 days, the Facility Permit holder shall calculate substitute data for each hour using the maximum hourly-recorded CEMS value during the service of the monitoring system.

e. Whenever prior CEMS data have not been available (0% availability), monthly mass emissions shall be calculated using Appendix A, Chapter 3, Subdivision D. For those sources operating without a fuel meter, process rate meter, or production rate meter, monthly mass emissions shall be calculated pursuant to Appendix A, Chapter 3, Subdivision I, Subparagraph 2c.

Table 3-A

MEASURED AND PROCESS VARIABLES FOR LARGE NO_X SOURCES

EQUIPMENT TYPE : BOILERS

EQUIPMENT	MEASURED VARIABLES
Boilers	1. Fuel flow rate; 2. Steam production rate;
Boilers with low NO_x burners	All variables identified for boilers.
Boilers with staged combustion	All variables identified for boilers.
Boilers with FGR	All variables identified for boilers; AND 3. Flue gas recirculation rate.
Boilers with SCR	All variables identified for boilers; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Boilers with SNCR	All variables identified for boilers; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;
Boilers with NSCR	All variables identified for boilers; AND 3. Natural gas (or other HC) injection rate.

EQUIPMENT TYPE : FURNACES

EQUIPMENT	MEASURED VARIABLES
Furnaces	1. Fuel flow rate; 2. Production rate;
Furnaces with low NO_x burners	All variables identified for furnaces.
Furnaces with combustion modification	All variables identified for furnaces.
Furnaces with SCR	All variables identified for furnaces; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Furnaces with SNCR	All variables identified for furnaces; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;

Table 3-A (CONTINUED)

MEASURED AND PROCESS VARIABLES FOR LARGE NO_X SOURCES

EQUIPMENT TYPE : OVENS

EQUIPMENT	MEASURED VARIABLES
Ovens	1. Fuel flow rate; 2. Production rate;
Ovens with low NO_x burners	All variables identified for ovens.
Ovens with combustion modification	All variables identified for ovens.
Ovens with SCR	All variables identified for ovens; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Ovens with SNCR	All variables identified for ovens; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;

EQUIPMENT TYPE : DRYERS

EQUIPMENT	MEASURED VARIABLES
Dryers	1. Fuel flow rate; 2. Production rate;
Dryers with low NO_x burners	All variables identified for dryers.
Dryers with combustion modification	All variables identified for dryers.
Dryers with FGR	All variables identified for dryers; AND 3. Flue gas recirculation rate.
Dryers with SCR	All variables identified for dryers; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Dryers with SNCR	All variables identified for dryers; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;
Dryers with NSCR	All variables identified for dryers; AND 3. Natural gas (or other HC) injection rate.

Table 3-A (CONTINUED)

MEASURED AND PROCESS VARIABLES FOR LARGE NO_X SOURCES

EQUIPMENT TYPE : PROCESS HEATERS

EQUIPMENT	MEASURED VARIABLES
Process heaters	1. Fuel flow rate; 2. Process rate;
Process heaters with low NO_x burners	All variables identified for process heaters.
Process heaters with combustion.modification	All variables identified for process heaters.
Process heaters with FGR	All variables identified for process heaters; AND 3. Flue gas recirculation rate.
Process heaters with SCR	All variables identified for process heaters; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Process heaters with SNCR	All variables identified for process heaters; AND 3. Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;
Process heaters with NSCR	All variables identified for process heaters; AND 3. Natural gas (or other HC) injection rate.
Process heaters with water (or steam) injection	All variables identified for process heaters; AND 3. Water (or steam) injection rate.

EQUIPMENT TYPE : INCINERATORS

EQUIPMENT	MEASURED VARIABLES
Incinerators	1. Fuel flow rate; 2. Process rate;
Incinerators with SCR	All variables identified for incinerators; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Incinerators with SNCR	All variables identified for incinerators; AND 3 Ammonia (or urea) injection rate; 4. Temperature of the inlet gas stream to SNCR;

EQUIPMENT TYPE : TEST CELLS

EQUIPMENT	MEASURED VARIABLES
Test cells	1. Fuel flow rate; 2. Shaft horsepower output;
Test cells with SCR	All variables identified for test cells; AND 3. Ammonia injection rate; 4. Ammonia slip
Test cells with Packed Chemical Scrubber	All variables identified for test cells; AND 3. Chemical injection rate.

Table 3-A (CONTINUED)

MEASURED AND PROCESS VARIABLES FOR LARGE NO_X SOURCES

EQUIPMENT TYPE : INTERNAL COMBUSTION ENGINES

EQUIPMENT	MEASURED VARIABLES
Internal combustion engines	1. Fuel flow rate; 2. Throttle setting
Internal combustion engines with combustion modification	All variables identified for internal combustion engines.
Internal combustion engines with Injection Timing Retard 4 degree	All variables identified for internal combustion engines.
Internal combustion engines with turbocharger, aftercooler, intercooler.	All variables identified for internal combustion engines.
Internal combustion engines with SCR	All variables identified for internal combustion engines; AND 3. Ammonia injection rate; 4. Temperature of the inlet gas stream to SCR;
Internal combustion engines with NSCR	All variables identified for internal combustion engines; AND 3. Natural gas (or other HC) injection rate.

EQUIPMENT TYPE : GAS TURBINES

EQUIPMENT	MEASURED VARIABLES
Gas turbines	1. Fuel flow rate; 2. Shaft horsepower output;
Gas turbines with Water or Steam Injection	All variables identified for gas turbines; AND 3. Water or steam injection rate;
Gas turbines with SCR and Steam Injection	All variables identified for gas turbines; AND 3. Ammonia injection rate; 4. Steam injection rate
Gas turbines with SCR and Water Injection	All variables identified for gas turbines; AND 3. Ammonia injection rate; 4. Water injection rate

Table 3-A (CONTINUED)

MEASURED AND PROCESS VARIABLES FOR LARGE NO_x SOURCES

EQUIPMENT TYPE : KILNS AND CALCINERS

EQUIPMENT	MEASURED VARIABLES
Kilns and calciners	1. Fuel flow rate; 2. Production rate;
Kilns and calciners with low NO_x burners	All variables identified for kilns and calciners.
Kilns and calciners with combustion modifications	All variables identified for kilns and calciners.
Kilns and calciners with FGR	All variables identified for kilns and calciners; AND 3. Flue gas recirculation rate.
Kilns and calciners with SCR	All variables identified for kilns and calciners; AND 3. Ammonia injection rate;
Kilns and calciners with SNCR	All variables identified for kilns and calciners; AND 3. Ammonia (or urea) injection rate;
Kilns and calciners with NSCR	All variables identified for kilns and calciners; AND 3. Natural gas (or other HC) injection rate.

EQUIPMENT TYPE : SULFURIC ACID PRODUCTION PLANTS

EQUIPMENT	MEASURED VARIABLES
Sulfuric acid plants	1. Fuel flow rate; 2. Production rate;

Table 3-B

REPORTED VARIABLES FOR ALL LARGE NO_x SOURCES

EQUIPMENT	REPORTED VARIABLES
All large NO_x sources	1. Total Monthly mass emissions from each source;

Table 3-C

RULE-SPECIFIC NOx CONCENTRATION LIMITS AND EMISSION FACTORS

BASIC EQUIPMENT	RULE	CATEGORY	CONCENTRATION NOx LIMIT
Heaters,	1109	> 40 mmBtu/hr in petroleum refineries	24 ppmv @3 % O_2, dry*
Boilers, Steam	1146	≥ 5 mmBtu/hr and < 40 mmBtu/hr	40 ppmv @3 % O_2, dry
Generators	1146.1	≥ 40 mmBtu/hr	30 ppmv @3 % O_2, dry
		≥ 2 mmBtu/hr and < 5 mmBtu/hr	30 ppmv @3 % O_2, dry
Internal Combustion	1110.1	Rich Burn Lean Burn	90 ppmv @15% O_2, dry 150 ppmv @15% O_2, dry
Engines	1110.2	> 50 bhp subject to Rule 1110.2(c)(2)(A)	36 ppm @ 15% O_2, dry
		> 100 bhp portable subject to Rule 1110.2(c)(2)(A)	36 ppm @ 15% O_2, dry
		> 500 bhp subject to Rule 1110.2(c)(2)(B)	36 ppm @ 15% O_2, dry Reference limit
		50-500 bhp subject to Rule 1110.2(c)(2)(B)	45 ppm @ 15% O_2, dry Reference limit
Nitric Acid Production	1159	All Sizes	450 ppmv
Turbines	1134	≥ 0.3 MW and < 2.9 MW Peaking Units and Emergency Standby Equipment	Emission factor or concentration limit determined as described in R. 1134(c)(1)

*** Converted from Rule limit, which is 0.03 lb/mmBtu.**

Table 3-D

EMISSION FEE BILLING NOx FACTORS

BASIC EQUIPMENT	TYPE OF FUEL	EMISSION FACTOR	HIGHER HEATING VALUE OF FUEL
Boilers,	Natural Gas	130 lb/mmscf	1050 mmBtu/mmscf
Ovens,	Refinery Gas	161 lb/mmscf	1150 mmBtu/mmscf
Heaters,	LPG, Propane, Butane	12.8 lb/mgal	94 mmBtu/mgal
Furnaces,	Diesel Light Dist. (0.05% S)	19 lb/mgal	137 mmBtu/mgal
Kilns,	Fuel Oil (0.1% S)	20 lb/mgal	150 mmBtu/mgal
Calciners,	Fuel Oil (0.25% S)	60 lb/mgal	150 mmBtu/mgal
Dryers	Fuel Oil (0.5% S)	55 lb/mgal	150 mmBtu/mgal
Internal	Natural Gas	3400 lb/mmscf	1050 mmBtu/mmscf
Combustion	LPG, Propane, Butane	139 lb/mgal	94 mmBtu/mgal
Engines	Gasoline	102 lb/mgal	130 mmBtu/mgal
	Diesel Oil	469 lb/mgal	137 mmBtu/mgal
Gas Turbines	Natural Gas	413 lb/mmscf	1050 mmBtu/mmscf
	Diesel Oil	67.8 lb/mgal	137 mmBtu/mgal

Table 3-E

UNREGULATED DEFAULT NOx CONTROL EFFICIENCIES

BASIC EQUIPMENT	FUEL	CONTROL EQUIPMENT	EFFICIENCY
Boilers, Ovens, Heaters, Furnaces	Gas Fired	Selective Catalytic Reduction (SCR)	90
		Thermal DeNOx (SNCR)	40
		Low NOx Burner	35
		Flue Gas Recirculation (FGR)	38
	Oil Fired	Wet Scrubber	70
		Selective Catalytic Reduction (SCR)	80
		Thermal DeNOx (SNCR)	40
		Low NOx Burner	25
	(Distillate)	Flue Gas Recirculation (FGR)	58
	(Residual)	Flue Gas Recirculation (FGR)	15
		None	0
Internal Combustion Engines	Gas Fired	Combustion Modification	55
	(Lean Burn)	Selective Catalytic Reduction (SCR)	68
	(Rich Burn)	Non Select. Catalytic Reduction (NSCR)	86
		Injection Timing Retard 4 Degree	15
	Oil Fired	Injection Timing Retard 4 Degree	20
	(Diesel)	Selective Catalytic Reduction (SCR)	80
	(Diesel)	Injection Timing Retard 2 Degree	18
	(Diesel)	Injection Timing Retard 4 Degree& Turbocharger & Aftercooler	40
		None	0
Turbines	Gas Fired	Water or Steam Injection	37
		SCR and Steam Injection	70
		SCR and Water Injection	60
	Oil Fired		
	(Diesel)	Water or Steam Injection	40
	(Distillate)	Water or Steam Injection	30
		None	0

Table 3-F

STANDARD OXYGEN CONCENTRATIONS

BASIC EQUIPMENT	FUEL	CONTROL EQUIPMENT	% O2, DRY
Boilers, Ovens, Heaters, Furnaces	Gas Fired	Selective Catalytic Reduction (SCR)	3
		Thermal DeNOx (SNCR)	3
		Low NOx Burner	3
		Flue Gas Recirculation (FGR)	3
	Oil Fired	Wet Scrubber	3
		Selective Catalytic Reduction (SCR)	3
		Thermal DeNOx (SNCR)	3
		Low NOx Burner	3
	(Distillate)	Flue Gas Recirculation (FGR)	3
	(Residual)	Flue Gas Recirculation (FGR)	3
Internal Combustion Engines	Gas Fired	Combustion Modification	15 in every category
	(Lean Burn)	Selective Catalytic Reduction (SCR)	
	(Rich Burn)	Non Select. Catalytic Reduction (NSCR)	
		Injection Timing Retard 4 Degree	
	Oil Fired	Injection Timing Retard 4 Degree	
	(Diesel)	Selective Catalytic Reduction (SCR)	
	(Diesel)	Injection Timing Retard 2 Degree	
	(Diesel)	Injection Timing Retard 4 Degree & Turbocharger & Aftercooler	
Turbines	Gas Fired	Water or Steam Injection	15
		SCR and Steam Injection	15
		SCR and Water Injection	15
	Oil Fired		
	(Diesel)	Water or Steam Injection	15
	(Distillate)	Water or Steam Injection	15